COMMONWEALTH OF MASSACHUSETTS
DEPARTMENT OF TELECOMMUNICATIONS & ENERGY

Investigation by the Department on its own Motion into Distributed Generation	)	DTE No. 02-38

INITIAL COMMENTS OF REALENERGY, THE JOINT SUPPORTERS, HESS MICROGEN, NUVERA FUEL CELLS, NORTH BATTERY DEVELOPMENT LLC AND BERKSHIRE DEVELOPMENT LLC

Pursuant to the Order Opening Investigation Into Distributed Generation, dated June 13, 2002, RealEnergy, Inc. ("Real Energy") The Joint Supporters[1], Hess Microgen, Nuvera Fuel Cells, North battery Development LLC and Berkshire Development, LLC offer the following comments.

1. RealEnergy is a Delaware corporation that develops, designs, installs, owns and operates distributed generation ("DG") systems throughout the United States. RealEnergy's DG systems often involve cogeneration and employ various technologies including: reciprocating engines, microturbines and solar photovoltaic systems. RealEnergy has offices in California and New York and is currently seeking opportunities to develop DG projects in Massachusetts. RealEnergy has offered written comments and testimony in similar proceedings in California, New York and Delaware as well as proceedings at the Federal Energy Regulatory Commission ("FERC"), at various state legislatures and to Congress. RealEnergy looks forward to working with the

[1] The Joint Supporters for purposes of these comments are the Distributed Power Coalition of America; Capstone Turbines; IEC Engineering, P.C.; Siemens Building Technology, District One (which services Western Massachusetts, Vermont, and upstate New York); and Harbec Plastics, Inc. Their representative is E Cubed Company, LLC.

Department and other Massachusetts stakeholders to reduce barriers to DG in the electricity industry.

2. The Joint Supporters for purposes of these comments are the Distributed Power Coalition of America; KeySpan Technology, Inc.; Capstone Turbines; IEC Engineering, P.C.; Siemens Building Technology, District One (which services Western Massachusetts, Vermont, and upstate New York); and Harbec Plastics, Inc. They can be reach via the E Cubed Company, LLC.

3. Hess Microgen is a leader in packaged cogeneration. Hess Microgen specializes in the design, manufacture, and sale of packaged cogeneration units ranging in size from 75 to 450kW for projects from 75kW to 4MW. Hess Microgen also owns and operates onsite cogeneration systems that pay for themselves entirely from facility-owner savings.

4. Nuvera Fuel Cells is a leading designer and developer of fuel power systems, fuel processors, and fuel cell stacks for the automotive, distributed generation, commercial and industrial markets in the U.S. and internationally.

5. North Battery Development, LLC is a company undertaking the development of homes throughout New England.

6. Berkshire Development, LLC, is a commercial property development company doing business in Massachusetts, New York and New Hampshire.

7. Developers of DG seek a fair and level playing field on which to compete in developing DG projects that offer efficient energy solutions to consumer energy needs. The DG industry, supported by the U.S. Environmental Protection Agency and U.S.

Department of Energy, believes that clean, efficient and new DG – particularly combined heat and power and renewable technologies – provides substantial benefits to ratepayers, the public at large, and distribution companies. These benefits come in the form of increased grid reliability and capacity, reduced capital and operating expenses for grid equipment, reduced peak electric-market power prices, and reduced air emissions.

8. We offer the following comments in the context of a larger national conversation regarding energy markets in general and DG in particular. On July 31, 2002, FERC issued a Notice of Proposed Rulemaking ("NOPR") regarding a Standard Market Design to rationalize the US wholesale energy market. In the NOPR, FERC identifies alternative power resources, including distributed generation, demand response technologies, and renewables as potentially important resources in facilitating demand elasticity, and notes that the market monitoring function should address entry barriers to distributed generation and demand-side resources. Moreover, several other states have developed, or are developing, interconnection standards and standby rates affecting the DG market. The Department should take advantage of this substantial body of work and experience in crafting policies to create and maintain a level playing field for DG in Massachusetts.

9. Our comments to the Department's questions are as follows:

1. <u>Refer to current distribution company interconnection standards and procedures in Massachusetts. Do these standards and procedures act as a barrier to the installation of distributed generation? If so, please describe</u>.

Current distribution company interconnection standards present barriers to DG, both in the content of the standards, and more importantly, in the application of those standards.[2] The primary effect of these barriers is to increase the transaction and project costs and development cycle time (which directly correlates to increased expense). Given that DG systems are often small in scale, the projects cannot support excessive transaction costs, unnecessary project expenses, or development cycles extended by many months due to interconnection review. It is imperative that the Department help create standards and rules that reduce transaction costs and other project costs to the minimum level required to ensure system safety and reliability. We identify four critical barriers relating to interconnection that should be addressed:

<u>First</u>, in specific instances, the published interconnection standards of the Massachusetts distribution companies create an absolute and explicit barrier to distributed generation. NStar's published standards are a primary example. Those standards expressly prohibit the parallel interconnection of DG systems within the Boston area. NStar will not interconnect DG in Boston in a parallel fashion because Boston is a "network system." NStar's rationale is that common DG safety and reliability measures are insufficient to protect the network system.

To be sure, distribution-system safety and reliability are paramount concerns. But these concerns too often have provided an unfounded excuse for distribution companies to delay, obstruct and increase the costs of DG installation and interconnection. We have successfully addressed safety and reliability concerns in other areas of the country and

[2] For purposes of these initial comments, we reviewed the interconnection procedures of the NStar Companies and Massachusetts Electric Company. That said, these comments are general in nature and not specifically targeted at any particular company's policies. Moreover, the comments reflect our experience with distribution companies and interconnection guidelines in other states and with the ISOs/RTOs under the regulatory authority of the FERC.

are confident these concerns can be adequately addressed in Massachusetts. For example, despite distribution company claims that DG cannot be safely installed within a "network system," RealEnergy has successfully obtained interconnection agreements for DG systems in parallel operation within a network system environment in Oakland with PG&E. In addition, Consolidated Edison has approved an interconnection design within a network system in Manhattan.

Second, under the existing interconnection standards, the distribution companies typically have an inordinate degree of subjective discretion regarding interconnection. A DG developer thus may expend significant resources without a firm understanding of what will finally be required in order to allow interconnection. At the end of the process, the distribution company can still refuse to interconnect without being held accountable.

Third, while the published interconnection standards and procedures of NStar and the other distribution companies are extensive, they lack uniformity and enough specificity to inform a DG developer what it must do to interconnect a DG system with the distribution company's system. Many times requirements will differ substantially from one adjacent distribution company to the next even though they operate distribution systems with essentially the same characteristics. While 220 C.M.R. § 8.00 *et. seq* mandates that distribution companies adopt interconnection standards for Qualifying Facilities ("QFs") and On-Site Generation Facilities (defined in 220 C.M.R. § 8.02 as DG systems of less than 60 kW), there is no such rule applicable to larger DG systems that are not QFs. Current distribution company interconnection standards are not always clear on these issues. Intentionally or not, disparate standards create uncertainty and add cost and risk to the underwriting of DG projects.

Fourth, interconnection standards are a barrier because they do not include criteria for fairly determining and allocating the true costs associated with interconnection. Currently, the costs associated with interconnection are determined largely by the distribution company and then charged to the DG developer. While the allocation of some costs to DG developers is fair and reasonable, distribution companies retain inordinate discretion over what costs are "necessary" (interconnection studies, engineering review, required safety equipment, etc.) and how they are allocated. For example, a distribution company in California required an extensive interconnection study that included mapping (from scratch) the existing local system, followed by an assessment of the impact of DG facility on that system. The DG developer was then asked to pay the $90,000 expense of the study. This represents an unnecessary expense and an inequitable allocation of costs. By contrast, in Delaware there is no charge for interconnection studies associated with DG unless the proposed interconnection poses "atypical" issues for the distribution system.

In summary, distribution company interconnection standards do present explicit and implicit barriers to DG. They allow the distribution companies inordinate and subjective discretion over matters of safety and cost. We urge the Department to address the concerns raised above in order to level the playing field.

1(a). If the current standards and procedures act as barriers to the installation of distribution generation, please describe what steps the Department should take to remove these barriers. As part of this response, please discuss whether the Department should establish uniform technical interconnection standards and procedures for distributed generation.

We suggest five steps the Department can take to remove or reduce the barriers presented by current interconnection standards and procedures:

First, the Department should prohibit unsupported prohibitions on interconnection. The Department should require the distribution companies to justify all express prohibitions on interconnection. We suggest that the reasoning underlying NStar's refusal to interconnect DG in parallel in Boston is no longer valid or supportable. Such blanket prohibitions fly in the face of proven experience elsewhere. Interconnection of DG in parallel with a network system can be done safely and reliably. The Department should require NStar to remove the Boston-area prohibition.

Second, the Department should take action to prevent distribution companies from abusing the discretion inherent in existing interconnection standards. The Department could establish a process whereby DG developers would have the right to file complaints with an independent arbitrator or hearing officer who could resolve interconnection disputes on an expedited basis. Unnecessary expenses should be shifted back to the distribution company. In addition, interconnection study expenses, where a study is required, should be shared between the DG developer and the distribution company, with the DG developer paying only for the portion of the study that assesses the impact of the DG system on the distribution company's system.

Third, the Department should discipline distribution companies who abuse their discretion in interconnection decisions. DG developers should be able to challenge abuses of discretion by distribution companies, and the Department should establish an expedited process to resolve such complaints. Disciplinary measures would serve as a strong incentive for distribution companies to confine themselves to legitimate technical concerns, and avoid pre-textual and obstructionist tactics.

Fourth, the Department should assess the legitimacy and applicability of the various safety and reliability concerns to different DG scenarios in order to distinguish legitimate issues of system protection from pre-textual concerns. To assist this process, the Department should create a collaborative technical conference that could resolve interconnection issues. This process worked, and is still working, well in California.

Fifth, the Department should adopt model interconnection standards (perhaps through the interconnection collaborative suggested above) that address the legitimate concerns of the distribution companies but also ensure fair treatment for DG developers. The uniform interconnection standards should be specific and objective, so that distribution companies cannot prevent interconnection by relying on discretionary, subjective or pre-textual rules. The model standards should incorporate the best practices from other states that have already adopted uniform standards, such as California, Texas, Delaware, and New York. (The New York interconnection standards, which were the first negotiated, are not ideal. But certain aspects of the New York standards, like the precertification of equipment, have proven very useful.) Massachusetts should take advantage of this prior work and not seek to reinvent the wheel. The Department should encourage open and productive technical discussions and not presume that any one party necessarily has technical superiority.

In developing model standards, the Department should consider the following suggestions:

A. The Department should adopt interim interconnection standards modeled largely on the interconnection standards adopted in California (the "CA Standards"). The CA Standards were developed in a collaborative process that included rigorous review and approval by the distribution companies, DG developers and other stakeholders. The CA Standards establish a reasonably fair and understandable process for interconnection of DG units less than or equal to 10,000 kW, including a process for expedited approval of DG systems meeting specific criteria. A copy of the CA Standards is attached to these Initial Comments as <u>Exhibit A</u>. The current interconnection standards of PG&E are attached as <u>Exhibit B</u>.

B. The model standards should include an expedited review and approval process for DG systems that satisfy certain design and operations thresholds for size, equipment specification and type of interconnection;

C. The model standards should include a process for pre-certifying equipment so that once approved, a DG system utilizing same components can be approved without extensive re-testing or re-certification.

D. The model for interconnection rules need to recognize that system impacts will not be the same in different portions of the system, i.e. a DG system will have a different impact on the bulk power system, the high-voltage distribution system and the low voltage distribution system. The Department should create exemptions from interconnection studies where such studies are not necessary. For example, both Texas and New York presume that the addition of 10MW to the bulk-power transmission system will have a de minimus impact. An analogous threshold might be established for facilities in the local distribution system, where a 2 MW addition may be considered de minimus. As an alternative, we note that California's interconnection standards have an expedited process for DG systems that are sized at a specified percentage of a local circuit's peak load flow. Distribution companies would have to rebut the presumption of de minimus impact in order to force an interconnection study.

E. The model interconnection standards should address both customer-owned DG as well as DG owned and operated by a third party. Many DG customers prefer to hire a third party DG company like RealEnergy to own and operate their DG systems. Interconnection standards and procedures should accommodate and facilitate such customer choice. (While this point seems obvious, it has been overlooked in the past. In California, for example, several distribution companies initially refused to modify the terms of their standard interconnection agreements, which assumed that their customer, who owned the property, was also the owner of the DG system. Ultimately, all of the California investor-owned utilities changed their policies to accommodate interconnection agreements with a third party.)

1(b). Please comment on whether the Department should adopt the IEEE's uniform technical interconnection standards, or the uniform standards adopted by other states, for use in Massachusetts.

While the Department should adopt uniform interconnection standards and procedures applicable to all distribution companies, the uniform standard should not be based on IEEE 1547. IEEE 1547 seeks to cover the entire range of interconnection issues in a single standard. The result to date of the IEEE's massive effort reflects the compromises necessary to accommodate the wide spectrum of interests that have participated in the IEEE process. Significant work remains to be done. We are not convinced at this point that the IEEE 1547 standard presents the most effective model for ensuring a fair and reasonable interconnection process in Massachusetts.

As mentioned above, the interconnection standards adopted in California, Texas, Delaware and other states offer a better model for the development of uniform Massachusetts interconnection standards. Indeed, we think that the

Department should adopt the California interconnection standard as an interim measure while final interconnection standards are developed. In any case, it is important that the process of formulating final interconnection standards in Massachusetts not further delay the development of DG in Massachusetts. Without interim standards, the development of DG will be chilled. Adoption of the CA Standards as an interim measure will allow installation of DG to proceed while permanent standards are developed.

2. <u>Refer to current distribution company standby service tariffs. Do these tariffs act as a barrier to the installation of distributed generation? If so, please describe</u>.

Currently, the majority of Massachusetts distribution companies do not have standby service tariffs that deal with DG. To our knowledge, only Cambridge Electric Light Company has a currently applicable standby tariff. Accordingly, we do not believe that standby service tariffs act as a substantial barrier to the installation of DG in Massachusetts. In fact, the Department has issued regulations located at 220 C.M.R. § 8.06 requiring distribution companies to provide supplementary, backup, maintenance and interruptible power to QFs and DG systems of 60 kw or less under rate schedules applicable *to all customers, regardlesss of whether they generate their own power.* That said, we would not be surprised if a Massachusetts distribution company initiated a standby rate case in the future.

Standby service tariffs do present a potential future barrier to the installation of DG in Massachusetts because of their potential to burden DG users with unreasonable and unjustified costs. Discriminatory standby rates in states like California have presented prohibitive barriers to DG. For example, under one set of tariffs that used to be effective in California, a customer installing a 1-MW DG system could have been assessed a fixed monthly charge of close to $20,000. This fee was wholly unjustified and not rationally related to the costs of providing the standby service. Needless to say, the barrier presented by such a charge is insurmountable. As mentioned below, California later suspended all standby charges and other discriminatory charges until new, more reasonable standards could be adopted.

2(a). Please discuss the appropriate method for the calculation of standby or back-up rates associated with the installation of distributed generation. As part of this response, please discuss whether other states have established policies regarding back-up rates associated with distributed generation that may be appropriate for adoption in Massachusetts.

In order to facilitate the development of DG in California, California passed legislation to prevent discriminatory treatment of customers who install DG. (Law SBX 1, enacting Section 353 of the Public Utility Code). Law SBX1 requires utilities to modify their tariffs so that all customers installing new distributed energy resources, in accordance with specified criteria, are served under rates, rules, and requirements identical to those of a customer within the same rate schedule that does not use distributed energy resources. The law also requires utilities to withdraw any tariff provisions that activate other tariffs, rates, or rules if a customer uses distributed energy. This includes standby rates.

We believe that California has the appropriate approach to standby charges. The Department should adopt a similar moratorium on standby rates or other charges that discriminate against DG while a final resolution of the underlying issues is worked out. This standby rate moratorium should last until DG has achieved a reasonable degree of market penetration. At that point, the Department will be able to assess the impact of DG on the electric distribution system accurately, and design fair and reasonable rate structures.

Once the impact of DG on the system is better understood, the appropriate method for the calculation of standby or back-up rates for DG should focus on a variable usage-based charge, with a zero or nominal fixed capacity cost component. Given a diverse asset base of DG systems, very little additional capacity is needed to provide standby or backup service. For smaller scale systems, the capacity cost of standby service is arguably negative, particularly if true locational costs and line losses are factored into the equation.

A fair determination of standby rates requires an accurate assessment of (1) the costs incurred by the distribution companies in providing the standby service to the DG system at the location and time that the back up service is provided, (2) a measurement of the degree to which the costs of the capacity serving such load were recovered by other means, (3) a measure of the benefits provided by DG that are not accounted for otherwise, and (4) an unbundling of the standby charge for distribution, transmission, and generation components.

We think that a fair assessment of these costs and benefits would often result in the recognition that in all circumstances, DG related standby rates should be much lower than standard or supplemental rates, and in many cases would, if fairly netted against the benefits of DG, result in a credit to the customers that use DG as part of their energy supply.

The reasoning for this conclusion lies in DG diversity and statistical probability. Simply put, if you have 10 MW of aggregate DG and 1 MW goes down, you still have 9 MW more capacity on the distribution system than you would have in the absence of the DG. The DG systems provide a net addition of capacity to the distribution company's distribution system. It is highly improbable that all of the DG systems will go down at the same time; the likelihood of this happening at a time of peak load is even more remote. Therefore, customers of the 10 MW of DG do not need anywhere near 10 MW of standby capacity. Rather, they need only a portion of that amount as determined using statistical probability analysis that takes actual downtime into account.

Standby rates (as well as monthly ratcheting demand charges) also can send an inappropriate price signal to the customer, preventing the customer from switching to the utility grid during periods of low utilization (such as the off-peak, when it might otherwise be more economical) because to do so would result in a higher demand charge. This deprives both the customer and the utility company of an economic benefit.

Calculation of standby or backup rates should also take into account the type of DG system and the type of service requested. This implies different standby rates for different DG systems and customer needs. We offer several examples to illustrate this point: (1) a customer with 1 MW of DG comprised of a single unit likely faces a much higher need for standby service than does a customer with 1 MW of DG comprised of five 200 kW units; (2) some customers may prefer interruptible standby service; (3) some DG systems supply all of a customer's load, while other DG systems are structured to cover only part of the load. To accommodate the variety of standby needs, a rate system that is focused on actual usage makes the most sense. At a minimum, if there is a fixed component, it should be based on actual daily demand, rather than a monthly ratchet. This reflects the nature of most DG, which serves a portion of a customer's load and is equivalent to any other demand reduction measure.

3. Please discuss the role of distributed generation with respect to the provision of reliable, least-cost distribution service by the Massachusetts distribution companies. What steps should the distribution companies take in order to identify areas where the installation of distribution generation would be a lower-cost alternative to system upgrades and additions? What steps should the distribution companies take to encourage the installation of cost-effective distributed generation in their service territories?

Many studies have shown the benefits of DG to the provision of reliable, least cost distribution services. These benefits include, among others:

A. Backup power supply and increased power reliability – With the addition of appropriate switching equipment, a DG system can be isolated within a facility or area when the utility is unable to supply that facility or area, thereby alleviating safety and productivity concerns associated with the loss of grid power.

B. Transmission and distribution upgrade deferrals -- Utilities can use DG to relieve transmission and distribution congestion, and defer investment in system upgrades.

C. Reduced transmission & distribution electric loss -- DG avoids electric losses associated with transporting power. Depending on the transport distance and the voltage of the line, the electric losses can range from 5% to 25%. Line losses approach the upper boundary on very hot days and at other times when the system is stressed and power is most needed.

For a more detailed discussion of the system benefits of DG, we refer you to testimony presented by Dr. Howard Feibus of Electrotek before the California Public Utilities Commission in a proceeding regarding the imposition of exit fees. His testimony is attached as Exhibit C to these comments.

The Department recognizes the system benefits that DG provides. Accordingly, we agree that distribution companies should be encouraged to identify areas where DG could be a lower-cost alternative to system upgrades and additions. The Department could give incentives to distribution companies that (1) identify areas where system upgrades are anticipated within the next two years, and (2) commit to working with DG providers to facilitate DG installations in those areas. A voluntary process could engender symbiotic working relationships between the distribution companies and DG providers for the benefit of all.

Nevertheless, in our experience the distribution companies may well need more than friendly encouragement to facilitate, rather than hinder, the development of DG. We suggest that, at a minimum, distribution companies be required to inform any customer who requests distribution service or upgrades, but who cannot be served in a timely fashion, that qualified DG companies may be able to offer a solution. The Department should also inform the DG Companies about who has received such a referral.

The Department also could require that, prior to proceeding with any major system upgrade or repair, a distribution company must prepare a public report identifying the problem the upgrade seeks to correct as well as a cost estimate. Qualified DG companies could then be given an opportunity to bid against the proposed upgrade, with the low bidder winning the right to install and operate the DG System subject to an agreement among the DG customer, the DG provider and the distribution company. Under that agreement, the parties could share in the avoided system-upgrade costs.

4. <u>What other issues are appropriate for consideration as part of the Department's investigation of distributed generation</u>?

We have two suggestions. <u>First</u>, the Department should consider amending some of the terms defined in its regulations under the Restructuring Act, as well as various other regulations, that are ambiguous and that expose DG providers to requirements ill-suited to their business. In particular, we ask that the Department that the term "competitive supplier" and 220 CMR § 11.00 does not include third party DG provider. While some licensing requirements may be appropriate for DG providers, the current "competitive supplier" licensing requirements are cumbersome when applied to DG producers. Also, we recommend amending the definition of "distribution company" in 220 C.M.R. § 1.02 to exclude DG providers. Finally, we suggest that the term "On-Site Generation Facility" in 220 C.MR § 8.02 be expanded to included DG systems up to 1 MW.

<u>Second</u>, the Department should review its natural gas regulations to make sure that DG users get access to gas without encountering discriminatory restrictions. Gas companies should be required to serve DG systems and developers like any other retail customer. For the near - to mid-term, natural gas

will be the primary fuel for the bulk of installed DG capacity. While we have not experienced any problems with gas supply in Massachusetts, obtaining firm supply has been an issue in other states. For example, Southern California Gas has an upper limit on the monthly amount of gas a customer can take and maintain eligibility for core bundled service. That limit is 21,600 therms, close to the amount of gas that a 600-kw DG project would consume. Without core bundled service, the DG provider would have to obtain gas from the wholesale market, something that is virtually impossible to do in the California market for a customer with that small of a load. The Department must prevent this type of problem from occurring in Massachusetts.

Conclusions

10. DG presents legitimate technical challenges to the existing electric distribution systems. We recognize that those systems are not currently designed to handle the immediate addition of thousands of megawatts of DG resources, but that is not a problem that should concern the Department right now: growth in DG will be measured and incremental. Today's distribution systems can accommodate a substantial increase in DG without any adverse impact. While proper planning is important, the prospect of future challenges should not be used as justification to stall current progress. A key role for the Department will be to sort the legitimate safety, reliability and operational concerns of the distribution companies from pre-textual claims that are based on anti-competitive impulses.

11. DG also presents a fundamental competitive challenge to the distribution companies. In most cases, DG will reduce distribution company

revenues. The benefits of DG will offset and in some cases outweigh the revenue loss. Nevertheless, so long as DG is perceived as a competitive threat, many distribution companies will not voluntarily incorporate of DG into the electric system. To be sure, a few distribution companies recognize the potential benefits of DG, and those distribution companies are working collaboratively to arrive at fair and equitable solutions to the challenges posed by DG. The Department's approach to these issues should accommodate both perspectives.

12. Ultimately, in a competitive market, some entities will prosper more than others. Protecting one participant to the detriment of others is fundamentally at odds with the developing competitive electricity market in Massachusetts. While it takes time to transition to a proper functioning market, in the long run, with proper oversight, the competitive threats and opportunities will spur all participants to offer higher-value solutions, products and services to customers. DG will become interwoven into the fabric of our electric infrastructure. The Department has a unique opportunity to help fashion the market in a manner that sets an example for the rest of the country.

13. In the long run, however, if DG is to flourish, distribution-company systems will have to move from a largely one-way energy distribution system to a load balancing mini-transmission organization. This transition will take time, present technical challenges, and cost money. These costs should be apportioned fairly among the beneficiaries, including DG owners, distribution company shareholders, energy consumers and other stakeholders. The fundamental premise underlying DG is that in appropriate applications, DG can

provide the least cost, most efficient solution to our energy needs. The benefits of DG to the economy will outweigh the costs of a transition to the new paradigm.

Respectfully submitted,

REAL ENERGY, INC., THE JOINT SUPPORTERS, HESS MICROGEN, NUVERA FUEL CELLS, NORTH BATTERY DELIVERY LLC, and BERKSHIRE DEVELOPMENT, LLC

Roger M. Freeman

Michael D. Vhay
Roger M. Freeman
Hill & Barlow
One International Place
Boston, MA 02110
(617) 428 3000

Q3VB01_.DOC (856043 v. 1)